ARR Allocation / MTEP Planning Processes

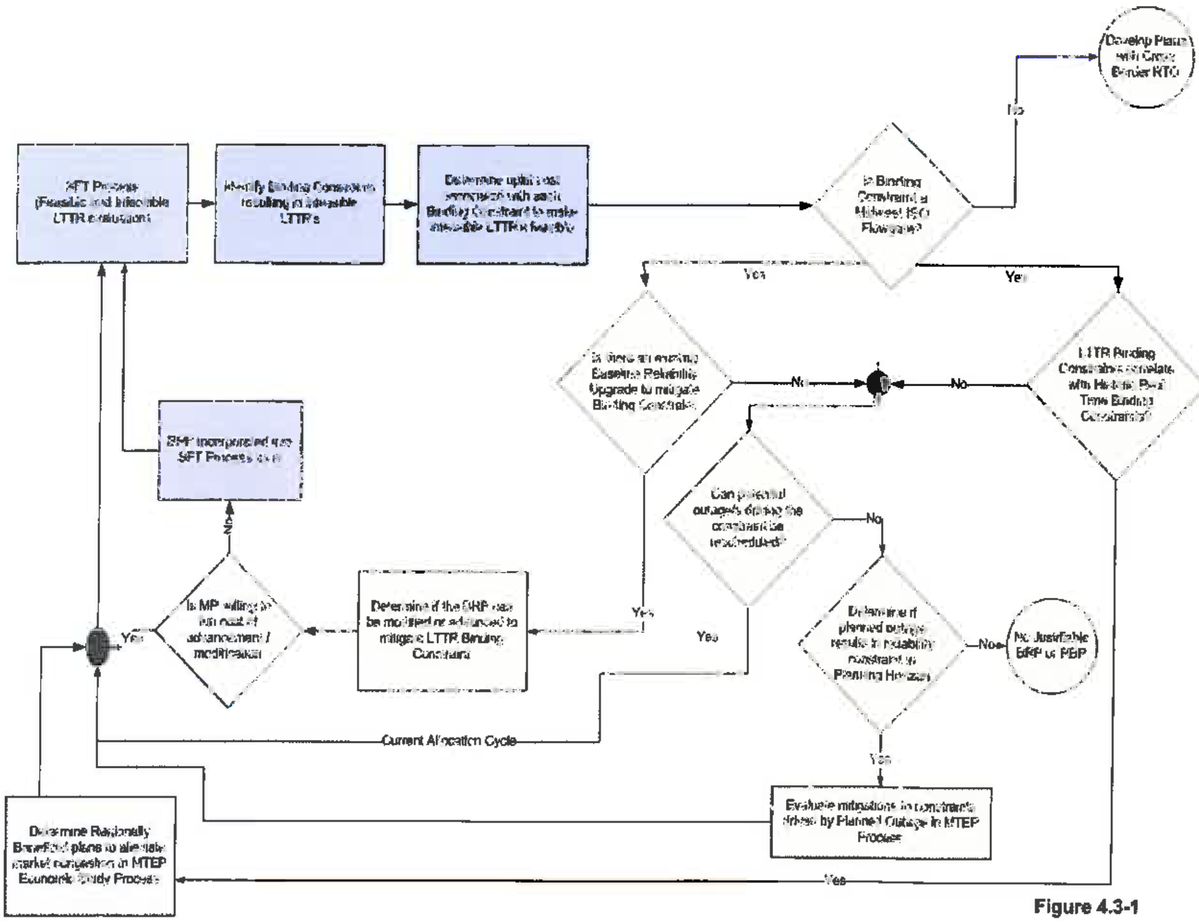


Figure 4.3-1

C.2 ARR Allocation Process - The Second and Subsequent Year Allocations and Infeasible LTTRs

Every ARR allocated in Stage 1A or Restoration becomes a LTTR. LTTRs have rollover rights, i.e., any LTTRs allocated the first year are guaranteed to be allocated in the second and subsequent years, as long as it is requested. This is true even if the LTTR request is deemed infeasible in next year's ARR allocation. The Restoration stage attempts to allocate a subset of the Stage 1A nominations that had to be curtailed to protect feasibility. In order to restore curtailed nominations, the Restoration Process will assign counter flow ARRs to some Market Participants.

All allocated LTTRs were at some point found to be feasible. LTTR infeasibility will be caused by changes in the ARR allocation cases from one year to the next. Such changes include:

- Network and commercial model updates, including topology changes and model corrections.
- Network topology changes due to the set of planned transmission outages considered in the ARR allocation cases. (Outages with a duration of seven or more days are included in the allocation cases).
- Changes in loop flow and carved-out assumptions.
- Variation in the nomination patterns:
    - A market participant may choose not to re-nominate existing LTTRs which may cause infeasibility of other LTTRs. This is partly addressed by the fact that all existing LTTRs are eligible for counter flow assignment starting Year 2 of the ARR allocation. However, counter flow will only be assigned to achieve feasibility of eligible base ARR entitlements.
    - Since LTTRs are not treated in the allocation process differently from non-guaranteed nominations, Stage 1A requests that did not exist in the previous allocation may cause the curtailment of LTTRs.
- Expiration of existing rights:
    - Termination of Point-to-Point services or retirement of generating units may lead to the termination of ARR Entitlements and associated LTTRs. This may cause infeasibility, as the terminated LTTRs may provide counter flow to other LTTRs.

The feasibility of the set of outstanding ARRs is required in order to ensure that sufficient FTR auction revenue is collected to fund ARRs. Since infeasible LTTRs may not be funded from the FTR auction revenue, their cost is distributed across all LTTR holders, in their LTTR MW share ratio.

Prior to future year ARRs / LTTRs allocation, the FTR and Pricing Administration Group will update the SFT model with the appropriate MTEP projects applicable to the allocation year. The SFT analysis will determine the feasible LTTRs that can be allocated subject to Flowgate constraint. Impact of planned outages will be considered in the SFT analysis. The MISO planning staff can work with the FTR and Pricing Administration Group with near-term planning MTEP models to assess the impact of planned outages on MISO Flowgates, assess the benefit of rescheduling outages and / or re-dispatch to alleviate the Flowgate congestion. This combined effort between the two groups will provide possible updates to the SFT to ensure the optimum allocation of ARRs / LTTRs.

C.3 MTEP Process - The Second and Subsequent Year Planning Models

As indicated in Figure 4.3-1, the MISO planning staff will use the various MTEP models to evaluate Flowgate constraints.

Near-term Planning / 1 – 2 Year Planning Horizon

As previously mentioned, the MISO planning staff can work with FTR and Pricing Administration Group during the study year SFT analysis to address planned outages / re-dispatch to alleviate Flowgate congestion.

Intermediate-term Planning / 1-10 Year Planning Horizon and
Long-term Planning Horizon / 1- 20 Year Planning Horizon

MISO planning staff can identify existing MTEP projects or work with the appropriate Transmission Owner to develop future projects required to alleviate Flowgate congestion under MISO control. This will be necessary in the second and subsequent years to ensure the feasibility of first year allocated LTTRs. Regarding Flowgates that are not within MISO control, MISO will need to develop plans with other RTOs as required.

The MISO planning staff will correlate LTTR binding Flowgates with real-time congestion hours. If there is no correlation, there is not likely to be a Market Efficiency Project solution to the LTTR binding constraint.

If there is correlation of LTTR binders with real-time congestion hours, there may be a MEP solution that would resolve the LTTR binding constraints. In this case, the binding Flowgates will be included in the annual process to evaluate the most congested Flowgates. An existing MEP may be modified to include the LTTR related economic benefits or a new MEP project can be developed to alleviate Flowgate congestion. MEPs can be advanced through the MTEP Process based on the project's economic merits. Reliability Based Projects will also need to be evaluated, relative to the LTTR economic related benefits at a Flowgate, to assess if the project's in-service date can be justifiable advanced in the MTEP process. To the extent that a proposed upgrade is an alternative solution to an otherwise identified system issue causing the need for a BRP or a MEP, and such an alternative upgrade would also result in a reduction in the amount of infeasible LTTR cost distribution that is required, such reduction in cost distribution will be considered in the economic comparison of alternatives to the BRP or MEP.

Intermediate-term and long-term BRP and MEP projects would be identified and included in the SFT model in the appropriate year as determined by the project in-service date.

4.3.9 Economic Evaluation of Potential Projects for the Short-term Planning Horizon

BRPs will be considered in the short-term planning process if they resolve a Transmission Compliance Issue that commences in the short-term planning horizon, where the short-term planning horizon is generally considered the greater of five years or the lead time of the project under consideration. In selecting BRPs for consideration for the short-term plan, consideration should be given to the incremental value of one alternative over another, where incremental value is defined as the present value of the incremental financially quantifiable benefits of an alternative project evaluated over the first 20 years of the project's life less the present value of the incremental annual revenue requirements of the alternative project evaluated over the first 20 years of the project's life. MEPs will be considered in the short-term planning process if some level of economic value can be realized within the short-term planning horizon on an annualized basis. Multi Value Projects (MVPs) will be considered in the short-term planning process if they resolve one or more Transmission Compliance Issues within the short-term planning horizon when qualifying under Criterion 1 or Criterion 3 or address one or more Transmission Value Issues within the short-term planning horizon when qualifying under Criterion 2 or Criterion 3, that is, begin generating positive economic value within the short-term planning horizon. All of these projects represent projects that have been studied under the long-term transmission process and have been transferred into Appendix B of the current or a previous MTEP.

Projects that qualify as MVPs under Criterion 2 or Criterion 3 should be considered for the Short-term Transmission Plan if they provide a Total MVP Benefit-to-cost Ratio of 1.0 or better. The Total MVP Benefit-to-cost Ratio of a specific MVP is based on the present value of annual financially quantifiable benefits and the present value of annual revenue requirements over the first 20 years of the project's life using a risk adjusted discount rate for the present value calculation.

The formula for the Total MVP Benefit-to-cost Ratio of an MVP is as follows:

$$\text{TotalMVPBC} = \sum_{yr} \{\text{PVProjectFinBen}(yr)\} / \sum_{yr} \text{PVProjectRevReq}(yr)\}$$

where

yr = Index of first 20 years of project life

PVProjectFinBen(yr) = The present value of the annual financial benefit calculated for the project in year *yr* based on a risk adjusted discount rate to be determined by the MISO.

PVProjectRevReq(yr) = The present value of the annual revenue requirements calculated for the project in year *yr* based on a risk adjusted discount rate to be determined by the MISO

In selecting potential projects for the short-term plan that qualify as MVPs based on Criterion 1, consideration should be given to the incremental value of one alternative over another, where incremental value is defined as the present value of the incremental financially quantifiable benefits of an alternative project evaluated over the first 20 years of the project's life less the present value of the incremental annual revenue requirements of the alternative project evaluated over the first 20 years of the project's life. For all MVPs, consideration should also be given to the long-term planning strategy selected for the Transmission System as a whole.

The specific type of financially quantifiable benefits associated with Transmission Value Issues addressed by an MVP, include the following:

- Production cost savings where production costs include generator startup, hourly generator no-load, generator energy and generator operating reserve costs. Production cost savings can be realized through reductions in both transmission congestion and energy losses. Productions cost savings can also be realized through reductions in Reserve Zone Operating Reserve requirements and, in some cases, reductions in overall Operating Reserve requirements. Production cost savings will be based on simulations using a production cost model with and without the project modeled under the reference future. Production cost savings will be determined for each of the first 20 years of a project's life.
- Capacity losses savings where capacity losses represent the amount of resource capacity required to serve transmission losses during the system peak hour. Reductions in MW losses during the system peak hour can be determined for a specific year using load flow simulations with and without the project modeled. The value of the loss reduction in a specific year can be determined by multiplying the transmission losses reduction in MW during the system peak hour by the product of the projected value of the CONE (Cost of Next Entrant) for the year and a factor equal to one plus the projected Planning Reserve Margin for the year.
- Capacity savings due to reduced Planning Reserve Margins. Planning Reserve Margin reductions can be estimated by executing Loss of Load Expectation studies with and without a specific project modeled and then multiplying the resulting reduction in the Planning Reserve Margin for the year by the product of the projected

system peak demand for the year and the projected value of the CONE (Cost of Next Entrant) for the year.

- Long-term cost savings realized by accelerating a long-term project target date in lieu of implementing a short-term project in the interim. This analysis compares the present value of the life-cycle cost of the short-term project vs. the present value of the cost of accelerating the long-term project.
- Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the Transmission System that is directly related to providing Transmission Service.

As each project is being considered for movement from Appendix B into Appendix A, sensitivity analyses may be performed if necessary to ensure recommended projects are effective under alternative future scenarios, where alternative future scenarios represent different assumptions regarding which projects currently in Appendix B may ultimately move to Appendix A.

4.3.10 Alternative Short-Term Plans

A "plan" represents the collection of projects that are candidates for recommendation for implementation to the Transmission Provider Board in the current planning cycle. To the extent that there are alternative short-term plans under consideration that resolve all Transmission Compliance Issues in the short-term planning horizon, these alternative short-term plans will be compared using the approach of Section 4.3.11. It is expected that most of the projects within an alternative short-term plan will be common to all alternative short-term plans (e.g., reliability based projects developed from the bottom-up planning process), but there may be differences in alternative short-term plans based on alternative sets of Dependent Transmission Projects developed in the long-term planning process, e.g., more than one variation on a 345 kV or higher voltage portfolio designed to address a particular long range requirement. [Dependent Transmission Projects are discussed in Section 2.3, MTEP Appendix A (III).] Alternative sets of Dependent Transmission Projects are expected to arise in the long-term planning process primarily as the result of alternative long-term plans developed to facilitate renewable energy standards, other public policy objectives and/or opportunities to enhance economic value for the entire MISO footprint. It is expected that only a subset of the projects included in Appendix B from the long-term planning process will be included in the alternative Short-term Transmission Plans within a given planning cycle as the key objectives of the alternative Short-term Transmission Plans are to resolve only the Transmission Compliance Issues and Transmission

Value Issues that commence in the short-term planning horizon, but in a manner that optimizes the value of transmission over the long-run.

It is important to note that development of alternative Short-term Transmission Plans will be a highly collaborative process between MISO planning staff, Transmission Owners and other stakeholders and will be facilitated through SPMs, the Planning Subcommittee and the Planning Advisory Committee.

4.3.11 Selection of the Preferred Alternative Short-Term Transmission

As discussed in Section 2.3 (III) of this document, selection of the preferred alternative Short-term Transmission Plan, which is equivalent to selection of the specific projects to be included in Appendix A of the MTEP, is based on the following process:

4.3.11.1 Determine the Total Financial Value of each Alternative Short-Term Transmission Plan

The first step is to determine the total financial value of each alternative Short-term Transmission Plan using the following formula:

$$\text{TotalValue(pl)} = \sum_{yr} \{\text{PVRefPlanARR(yr)} + \text{PVAnnualFinBen(pl,yr)} - \text{PVARR(pl,yr)}\}$$

where

pl = Index of alternative Short-term Transmission Plans being evaluated

yr = Index of first twenty years of a Short-term Transmission Plan

TotalValue(pl) = The present value of the total financial value generated by alternative Short-term Transmission Plan *pl* expressed in dollars and based on a risk adjusted discount rate to be determined by MISO.

PVRefPlanARR(yr) = The present value of the annual revenue requirements in year *yr* of the

reference alternative short-term plan, where the reference alternative Short-term Transmission Plan is the Short-term Transmission Plan with the lowest present value of annual revenue requirements over the first 20 years of the plan's life based on a risk adjusted discount rate to be determined by MISO.
This term represents the reference economic value of resolving Transmission Compliance Issues and is assigned to each alternative Short-term Transmission Plan since each alternative Short-term Transmission Plan must resolve all Transmission Compliance Issues.

PVAnnualFinBen(pl,yr) = The present value of the annual financially quantifiable benefits of alternative Short-term Transmission Plan *pl* in year *yr* based on a risk adjusted discount rate to be determined by MISO.

and

PVARR(pl,yr) = The present value of the annual revenue requirements of alternative Short-term Transmission Plan *pl* in year *yr* based on a risk adjusted discount rate to be determined by MISO.

The annual financially quantifiable benefits of an alternative Short-term Transmission Plan which results from resolution of Transmission Value Issues within the alternative Short-term Transmission Plan may include the following:

- Production cost savings where production costs include generator startup, hourly generator no-load, generator energy and generator operating reserve costs. Production cost savings can be realized through reductions in both transmission congestion and energy losses. Productions cost savings can also be realized through reductions in Reserve Zone Operating Reserve requirements and, in some cases, reductions in overall Operating Reserve requirements. Production cost savings will be based on simulations using a production cost model to test each alternative Short-term Transmission Plan under each Future which has been modeled in the long-term planning process. A weighted average production cost based on the probabilities of each Future modeled in the long-term planning process will be used. Production cost savings will be determined for each of the first twenty years of each alternative Short-term Transmission Plan.
- Capacity losses savings where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour. Reductions in MW losses during the system peak hour can be determined for a specific year using load flow simulations of each alternative plan. The value of the loss reduction in a specific year can be determined by multiplying the transmission losses reduction in MW during the system peak hour by the product of the projected value of the CONE (Cost of Next Entrant) for the year and a factor equal to one plus the project Planning Reserve Margin for the year.
- Capacity savings due to reduced Planning Reserve Margins. Planning Reserve Margin reductions can be estimated for a specific year by executing Loss of Load Expectation studies for each alternative Short-term Transmission Plan and then multiplying the resulting reduction in the Planning Reserve Margin for each year by the product of the projected system peak demand for the year and the projected value of the CONE (Cost of Next Entrant) for the year.
- Long-term cost savings realized by accelerating a long-term project start-date in lieu of implementing a short-term project in the interim. This analysis compares the present value of the life-cycle cost of the short-term project vs. the present value of the cost of accelerating the long-term project.

- Any other financially quantifiable benefit to Transmission Customers related to the provision of Transmission Service resulting from an enhancement to the Transmission System.

4.3.11.2 Determine the Total Plan Benefit-to-Cost Ratio of each Alternative Short-Term Plan

The second step is to determine the Total Plan Benefit-to-cost Ratio of each alternative Short-term Transmission Plan using the following formula:

$$TotalPlanBC(pl) = \sum_{yr} \{PVRefPlanARR(yr) + PVAnnualFinBen(pl,yr)\} \Big/ \sum_{yr} \{PVARR(pl,yr)\}$$

where

pl = Same as formula in Section 4.3.11.1
yr = Same as formula in Section 4.3.11.1
TotalPlanBC(pl) = The Total Plan Benefit-to-cost Ratio associated with alternative Short-term Transmission Plan *pl*
PVRefPlanARR(yr) = Same as formula in Section 4.3.11.1
PVAnnualFinBen(pl,yr) = Same as formula in Section 4.3.11.1
PVARR(pl,yr) = Same as formula in Section 4.3.11.1

4.3.11.3 Develop a Final List of Alternative Short-Term Transmission Plans for Further Review

A final list of alternative Short-term Transmission Plans will be developed as follows:

- The alternative Short-term Transmission Plan that produces the highest Total Plan Value as determined in Section 4.3.11.1 of this document will be placed on the final list.
- The alternative Short-term Transmission Plan that produces the highest Total Plan Benefit-to-cost Ratio as determined in Section 4.3.11.2 of this document will be placed on the final list.

- Any alternative Short-term Transmission Plan with a Total Plan Value not less than 75% of the highest Total Plan Value of all alternative Short-term Transmission Plans and a Total Plan Benefit-to-cost Ratio not less than the 75% of the highest Total Plan Benefit-to-cost Ratio of all alternative Short-term Transmission Plans will also be placed on the final list.

4.3.11.4 Select the preferred Short-term Transmission Plan

After development of the final list of alternative Short-term Transmission Plans, the following factors will be considered by MISO planning staff to select the preferred alternative Short-term Transmission Plan for recommendation to the Transmission Provider Board:

- Consideration of how well the alternative Short-term Transmission Plan fits into the overall long range transmission expansion strategy.
- Feedback from Transmission Owners and other stakeholders on the merits of each alternative Short-term Transmission Plan.
- Comparison of the Total Plan Value calculated for each alternative Short-term Transmission Plan
- Comparison of the Total Plan Benefit-to-cost Ratio calculated for each alternative Short-term Transmission Plan
- Non-financial quantifiable factors such as (but not limited to) the amount of new right-of-way required for each alternative Short-term Transmission Plan.
- Qualitative factors such as (but not limited to) the longevity or overall robustness of each alternative Short-term Transmission Plan.
- Regulatory risk factors such as (but not limited to) the number of state approvals required to implement each alternative Short-term Transmission Plan
- Other pertinent information that may be applicable.

Once the preferred Short-term Transmission Plan has been selected, all projects associated with the preferred Short-term Transmission Plan will be flagged to move to Appendix A of the applicable expansion plan for approval by the Transmission Provider Board. That is, the projects moving to Appendix A of a specific MTEP represent the recommended Short-term Transmission Plan for that MTEP.

4.4 Long-term Planning

4.4.1 Market Efficiency Project Introduction

Long-term planning focuses on ensuring an optimum long-term transmission expansion plan. Long-term planning focuses on robustness under future uncertainty, long-term policy objectives and strategies to assist in maximizing the value of the Transmission System over the long-run. Unlike short-term plans, long-term plans are not yet approved for construction, but instead are implemented in phases by integrating long-term planning results into a series of optimized short-term plans. The key objective of long-term planning is to develop optimal long-term solutions that can guide and, when appropriate, be integrated into short-term plans for implementation.

4.4.2 Process Steps for Long-term Planning

The long-term planning process takes a long-term view of Transmission Issues to establish an efficient plan that is value driven, and when integrated with shorter-term plans endeavors to produce the most efficient and reliable Transmission System achievable. The flow of this process is outlined below in Figure 4.4-1 and consists of the following steps. The detailed process flow diagram is outlined in Figure 4.4-2.

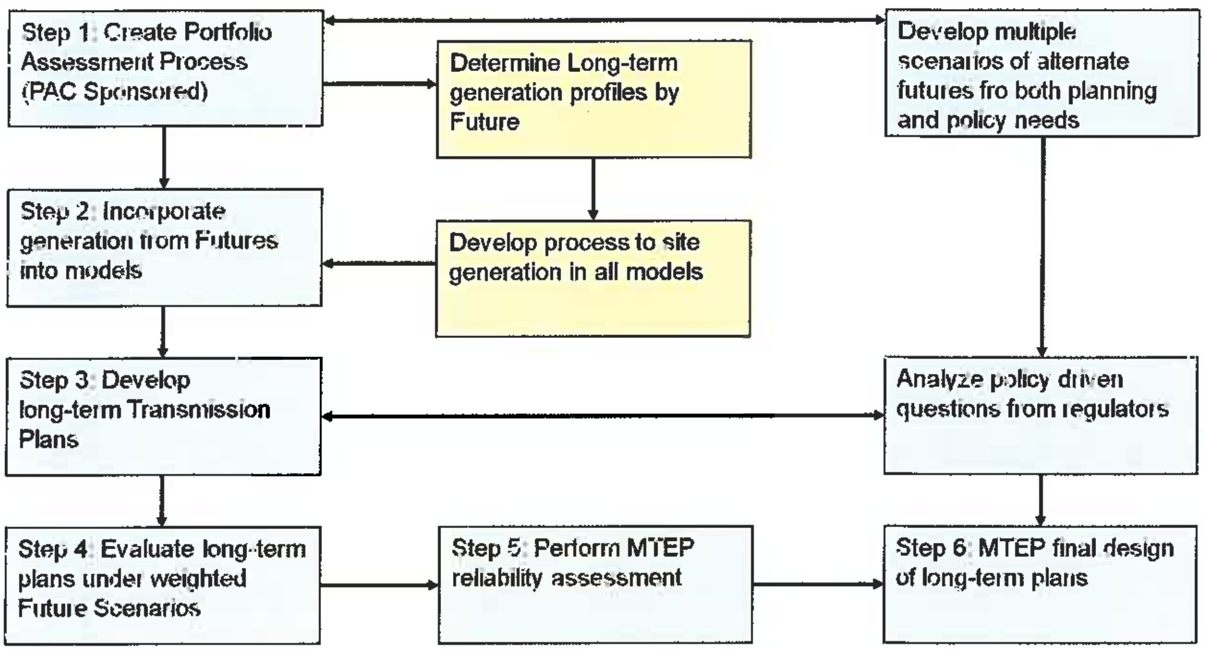


Figure 4.4-1 Process Diagram – Integrating Reliability Requirements with Economic Efficiency Goals

4.4.2.1 Create a generation portfolio forecast and assessment process

The MISO Generation Interconnection Queue provides initial information into new generation being proposed within the footprint. This is supplemented a) resource requirements driven by regulatory mandates, state laws and/or federal laws (e.g., State Renewable Portfolio Standards, etc.), and b) with other intelligence on new generation projects and long-range integrated resource plans not yet reflected in the MISO Generation Interconnection Queue. Generation portfolio assessments are developed for each of the three planning regions within MISO.

4.4.2.2 Incorporate generation from Futures into models

Once the future generation from the portfolio assessment process is identified, it must be sited. Transmission planning models used by MISO require that new generating units must have their physical location and interconnection characteristics specified in order to establish initial reference conditions. New generating units in the Generation Interconnection Queue have known sites and specific interconnection parameters.

With regard to future generation not yet in the Generation Interconnection Queue, a resource's site and/or transmission interconnection infrastructure is not yet known. In these cases, MISO planning staff must develop assumptions about the new resource's location and interconnection features under a number of alternative futures.

For its long-range planning studies, MISO planning staff identifies likely sites for new generating resources, and presumes that new interconnecting transmission facilities will be constructed as necessary to support generating plants that may not be located adjacent to existing transmission facilities. MISO also considers the existing Renewable Energy Zones when determining potential sites for renewable resources needed to meet renewable portfolio standards. This approach endeavors to provide reasonable assumptions regarding fixed-in-place generation to provide a starting point for integrated system reliability and economic enhancement modeling and analysis. In this process, results from completed power flow modeling are used to provide input data to MISO's production cost model. A study horizon of 20 years will be utilized for long-term planning evaluations to determine project benefits. The long-term planning evaluation process is structured to ensure robustness by utilizing multiple Futures to analyze future impacts in determining the benefit of system expansion projects.

4.4.2.3 Design preliminary long-term transmission plans

Each alternative Future is first simulated through power flow modeling to estimate loads and generating capacity requirements. Results from this simulation are then input into a production cost model that estimates the cost to generate and transmit electric power to customers. This modeling assumes a "copper sheet" transmission system, with no constraints, so that power flows unrestricted from generators to loads. Load flow and generation dispatch estimates from this initial round of modeling are used to simulate one or more hypothetical high voltage overlay sufficient to meet projected energy flow requirements. Further modeling of hourly load flow estimates is used to refine the size and characteristics of the alternative long-term transmission plans. Hourly flow information is also combined with transmission constraint identification tools linked to the production cost model to iteratively refine the long-term transmission plans. Each of these modeling processes is performed collaboratively with stakeholders in an open planning process. Projects associated with each of the preliminary long-term transmission plans will be subjected to the effectiveness testing described in Section 2.3 (II) to ensure they effectively address one or more future Transmission Issues. All projects associated with the alternative long-term plans that demonstrate the ability to effectively address one or more future Transmission Issues based on this effectiveness testing will be placed into Appendix B.

4.4.2.4 Evaluate alternative long-term transmission plans for resolution of Transmission Compliance Issues

The process described in Step 3 produces one or more alternative long-term transmission plans. It is necessary that each alternative long-term plan resolve key Transmission Compliance Issues under all Futures. To this end, each preliminary long-term transmission plan is analyzed under the uncertainty conditions of every Future scenario to ensure it resolves key Transmission Compliance Issues, where key Transmission Compliance Issues will be established by MISO and Transmission Owners and represent those Transmission Compliance Issues that require major expansions or modifications to the Transmission System to gain compliance. A long-term transmission plan that resolves the key Transmission Compliance Issues under every Future scenario is considered robust with regard to Transmission Compliance Issues. To the extent that key Transmission Compliance Issues are not satisfied by a specific alternative long-term plan, MISO will work with Transmission Owners and other stakeholders to make necessary adjustments to the alternative long-term plan.

Each transmission plan is tested for robustness by evaluating its performance under every Future scenario and assessing its test results for selected attributes that may include the following:

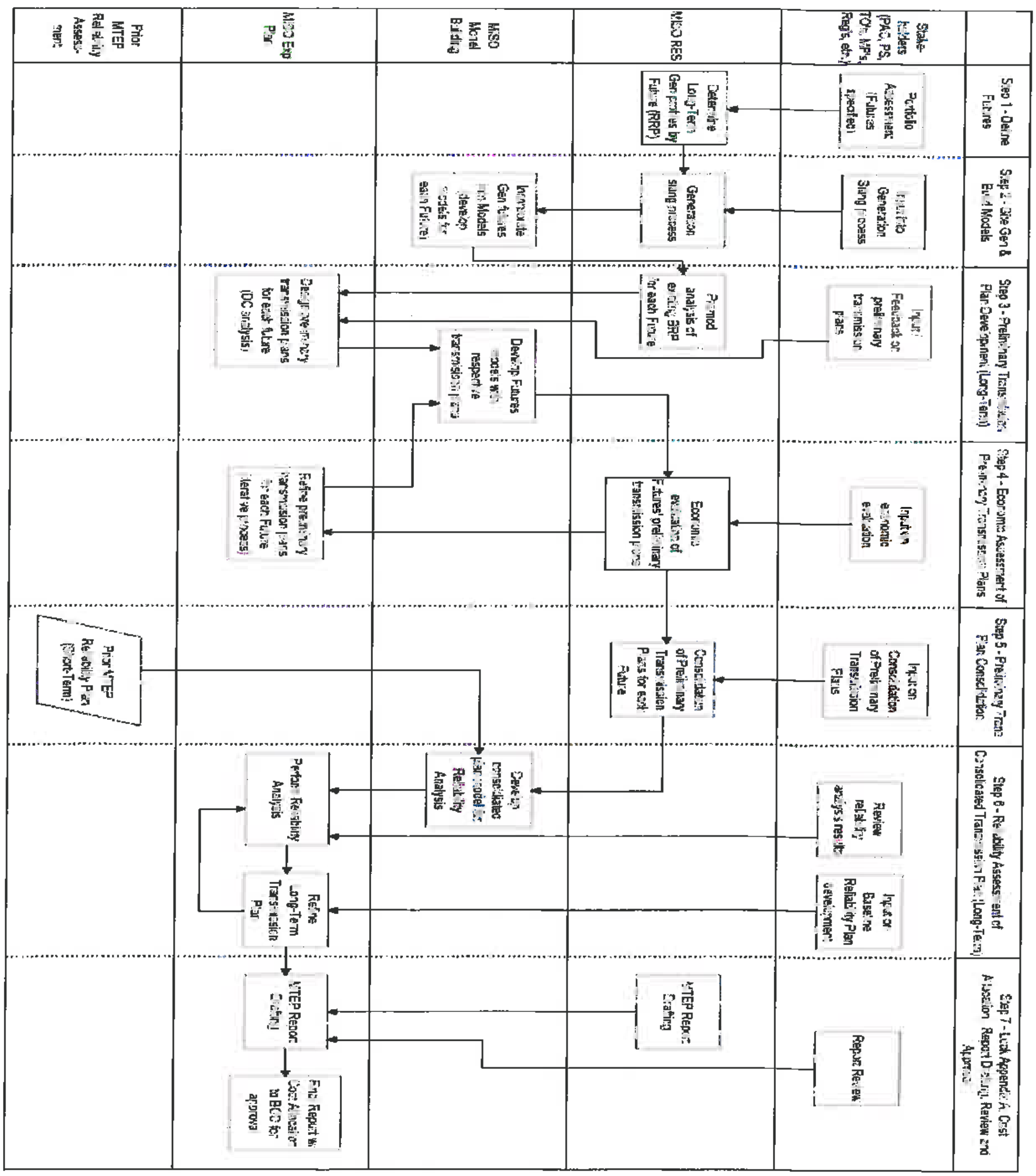
- LOLE / Reserve margin effects
- Short and long-term cost metrics
- Investor impacts
- Economic development impacts
- Degree of difficulty in developing
- Environmental compliance
- National security issues

Potential transmission plans are ranked according to their performance on these attributes to determine which was most robust under the Future scenarios considered.

4.4.2.5 Evaluate Long-term Transmission Plans for Transmission Value Robustness

All alternative long-term plans that resolve the key Transmission Compliance Issues outlined in Step 4 will be analyzed for value, where value represents the difference between benefit and cost. In general, financial benefits considered during this step include, but are not necessarily limited to, production cost savings, reserve margin reductions and capacity losses reduction. In analyzing these financial benefits, analysis will be completed under multiple Futures to ensure robustness. Each future will have a weighting factor applied based on the likelihood of that future relative to other futures, and overall financially quantifiable benefits will be determined by applying these weighting factors to the financial benefits determined for each future to determine a weighted average benefit. The weighting factors to be applied to each future will be determined by MISO working in collaboration with the Planning Advisory Committee. The alternative long-term plan that, in the judgment of MISO planning staff based on preliminary analyses provides the highest level of long-term value will represent the modeled long-term plan. While the modeled long-term plan will include projects in Appendix A and Appendix B, the modeled long-term plan in general is not yet approved for construction. All projects in Appendix A are also associated with the current or a previous short-term plan which is approved for construction. That is, the current and previously approved short-term plans that have not yet been implemented are subsets of the modeled long-term plan. However, the modeled long-term plan will also include projects that have not yet been approved for construction. These projects are located in Appendix B of the current expansion plan and designated with an asterisk. It is important to emphasize that the modeled long-term plan is not yet approved for construction, but instead represents the default long-term plan at a single point in time. Only short-term plans, which are guided by the results of long-term planning, are approved for construction. Long-term plans will change over time and will guide development of the short-term plans.

Figure 4.4-2 – Futures and MEP Development – Process Flow Diagram



4.4.3 Data Sources and Assumptions for Long-term Planning Models

The data for the long-term planning studies are from a central database. The initial data (load, generator, fuel, and environmental data) in database are provided by a vendor. The vendor also provides incremental updates on the data each month and a large update once a year. The vendor data can be modified in whole or in part with newer or more appropriate data as desired.

The sources of the data provided by the vendor are:

- Federal Energy Regulatory Commission (FERC) Forms 1, 714
- Energy Information Agency Forms (860, 867, 411, 412, 423)
- North American Electric Reliability Council (NERC) Electric Supply and Demand (ES&D) reports
- Generating Availability Data Systems (GADS) Data
- Environmental Protection Agency (CEMS data)
- ISO, OASIS web sites
- Energy company web sites

4.4.3.1 Demand and Energy

MISO planning staff replaces the company peak demand and energy data provided by the vendor with the latest Module E reported data. Included in the Module E data are Interruptible Load, Direct Load Control, and 10 year projections for demand by each company. Module E load data includes losses.

The demand for each Local Balancing Authority is the non-coincident value reported to MISO for resource adequacy reporting. This data is reported to MISO each year and represents the non-coincident peak demand for each company. The hourly load profile for each company will use the load profile from the vendor-supplied data. Module E only provides 10 years of load forecast data. Each individual company's Module E reported growth rate over the first 10 year period is averaged and extended over the remaining 10 years of the study period.

Individual company's annual energy requirements are calculated based on its demand and its load factor reported in the latest Module E (based on the report year's demand and energy).

4.4.3.2 Generation Data

Areas outside MISO are modeled using the generation information in the vendor database. Generation within MISO is adjusted to represent what is reported through the resource adequacy provisions of Module E. Changes include activating or deactivating units and adjusting the maximum capacity of the unit. All other operating characteristics use the default data from the vendor. In addition to generator changes reported through the resource adequacy process, generators in the MISO Queue which have a signed interconnection agreement (IA) are modeled. The new generators identified in Step 1 and Step 2 are also being included in later steps study.

4.4.3.3 Fuel Data

The source for the fuel forecasts in the vendor database is typically the Platt's database, Henry hub forecasts, and EIA forecasts. The vendor contracts with Platt's for various fuel forecasts. The vendor uses the Platt's forecasts for natural gas as a starting pointing and then uses the basis differential inherent in Platt's forecast for Natural Gas combined with NYMEX Henry Hub futures prices for the first 18 months of the forecast. For the forecast beyond 18 months, the Energy Information Administration (EIA) natural gas forecast for the Henry Hub serves as the base index. The basis differential to each area is then applied against the EIA forecast of the Henry Hub prices.

The oil forecasts are based on futures contracts with no basis differential. Heavy Oil forecasts in this PROMOD study are adjusted based on Crude Oil prices and Light Oil forecasts are adjusted based of Heating Oil prices from NYMEX.

The coal forecasts are from Platts directly and these forecasts include transportation costs.
The vendor updates the fuel forecasts every quarter.

4.4.3.4 Environmental Data

Emissions production rates for an effluent are spread across all fuels assigned to a generator. Price forecast data is provided for SO2 and NOX (by trading program) emission allowances. All this data is from the vendor database.

4.4.3.5 Event File

Monitored Flowgates in PROMOD constitute an "event file". The source for this event file is MISO Book of flowgates and NERC Book of flowgates. Certain flowgates may have operating guides associated with them in real time operations. Hence the "event file" is scrubbed to remove any flowgate that might have an operating guide associated with them. Besides these flowgates, PROMOD Analysis Tool (PAT) is also used to identify new flowgates with overflow potential in study years and add them in the event file.

4.5 Regional Participation

MISO planning staff coordinates transmission expansion studies with adjacent, interconnected transmission providers, Regional Entities, and RTOs. MISO has coordination agreements in place with the PJM RTO (MISO-PJM Coordinated System Plan), Southwest Power Pool (SPP), and Tennessee Valley Authority (TVA). The coordinated agreements call for Coordinated System Plans (CSP) with the other regional planning entities. The primary purpose of these CSPs is to contribute, through coordinated planning, to the on-going reliability and the enhanced operational and economic performance of the systems of the parties.

To accomplish this purpose, the CSP will:

- Integrate the Parties' respective transmission plans, including any market-based additions to system infrastructure (such as generation or merchant transmission projects) and Network Upgrades that were considered.
- Set forth actions to resolve any impacts that may result across the seams between the Parties' systems due to such system additions or Network Upgrades; and
- Describe results of the joint transmission analysis for the combined transmission systems, as well as the procedures, methodologies, and business rules utilized in preparing and completing the analysis.

The Inter-Regional Planning Stakeholder Advisory Group (IPSAG), which consists of stakeholder and the planning staff of MISO and other neighboring planning regions, will meet at scheduled times to discuss planning issues, concerns, and activities related to CSPs. The IPSAG also exchanges data regarding planning model assumptions for system performance, interface expansions, and network contingencies. The meeting notifications, schedules, and materials of IPSAG meetings are communicated to the stakeholders via Planning Sub-committee and Planning Advisory Committee email exploder lists.

4.6 Dispute Resolution

Disputes involving proposed expansion planning projects are resolved in accordance with Attachment HH ("Dispute Resolution Procedures") of MISO's FERC Electric Tariff. Attachment HH includes provisions for dispute resolution through progressive steps consisting of informal negotiation, mediation, and arbitration. It also includes provisions for the formation of MISO's Alternate Dispute Resolution Committee, along with procedures for Expedited Dispute Resolution.

The dispute resolution process begins with a disputing party informing MISO of the subject of a dispute, and designating a representative for further contact. MISO's Client Relations Representative will attempt to resolve the issue with the disputant's representative. If the dispute cannot be resolved at this level, the disputing party notifies MISO and identifies a company officer authorized for further negotiation. MISO likewise designates a company officer, and the two officers attempt to resolve the dispute through informal negotiation.

In the event that the companies' officers cannot resolve the dispute, the matter is presented to the Alternative Dispute Resolution Committee. This Committee (described below) determines if the matter is sent to mediation or arbitration. For mediation, the disputing parties first agree upon a mediator. The mediator meets with the disputants, where each party may present written statements of issues and positions. The mediator evaluates the parties' statements, and provides written, non-binding recommendations to resolve the dispute.

For arbitration, the disputing parties may agree upon a single arbitrator, or a panel of three arbitrators may be selected according to the procedures of Attachment HH. The arbitrators are authorized to hold evidentiary hearings, if needed, as part of a process to discover relevant facts. The arbitrator(s) issue a written decision based on the evidence in the record, the applicable MISO Agreement or Tariff, applicable state and federal standards, and relevant decisions made in prior arbitration proceedings. The decision of the arbitrator(s) is binding, subject to applicable state and federal laws and approvals.

The Alternative Dispute Resolution Committee consists of six representatives selected by the Transmission Provider Board. The Committee is intended to reflect the diversity of MISO, so that Committee members are selected according to the size, type, and geographic location of Owners and Members. No more than one member on the Committee may be a representative of the same Owner or Member. Among its responsibilities, the Committee is charged with identifying and maintaining a pool of qualified individuals to serve as mediators or arbitrators.

Expedited Dispute Resolution procedures may be applied in disputes involving real-time operation (affecting system security or reliability) or available transmission capacity determinations. Disputes are resolved according to the system described in the preceding text, but disputants proceed through the process on an expedited schedule. In some cases, specific MISO officer positions have authority (from Attachment HH) to negotiate disputes under expedited conditions.

5 Long-term Transmission Service Requests

5.1 Introduction

Requests for transmission service must be evaluated for impacts on system reliability. MISO planning staff is responsible for evaluation of long-term firm transmission service requests with reservation periods of one year or longer, which will be referred to as requests in the planning time horizon. The evaluation process is initiated when a transmission customer submits a qualifying request on MISO OASIS. Certain requests for firm transmission service require power flow network analyses in addition to a flow based analysis, in order to evaluate the system's ability to accommodate the request. The Tariff and other MISO documents identify the procedural requirement of the transmission service reservation process. This document provides information to be used in the performance of network analyses of requests for firm transmission service under the Tariff by MISO, or others performing such analyses on behalf of MISO. Studies may be performed directly by MISO planning staff, or may be performed by others on behalf of MISO under MISO guidance. In all cases, MISO is responsible for the final study results and conclusions, and will have decisional control over the transmission service process.

5.2 Triage

Whenever a long-term transmission service request is submitted on OASIS, Tariff Administrators put the request in "Study" mode which indicates MISO planning staff will further review the request. MISO planning staff runs a daily query that imports the Study TSRs from OASIS and then starts processing them based on queue priority. MISO planning staff then take appropriate steps to process the transmission service requests based on the type of request as described below.

5.2.1 Processing of "Renewal" Transmission Service Request:

MISO planning staff do not restudy renewal transmission service requests. Upon receiving such requests, the MISO planning staff verify and ensure that the parameters of the renewal TSRs match the parameters of the parent TSR and meet the FERC Order 890 rollover reform requirements as posted on MISO OASIS. The renewal TSR must start immediately following the expiration of the parent TSR. If the renewal meets these requirements, MISO planning staff will request the submittal of two copies of the Specification Sheets which are due within 15

Calendar Days after MISO makes the request by posting comments on OASIS. If MISO does not receive the specification sheets by the posted due date, MISO will refuse the TSR on OASIS. If MISO receives the specification sheets, then the TSR will be accepted and the customer shall have 15 days to confirm the TSR on MISO OASIS. After MISO accepts the TSR, it triggers an automatic timer on MISO OASIS for that particular TSR and customer's failure to confirm the TSR within that 15 day period will result in an automatic refusal of the TSR, also referred to as "Retracted."

5.2.2 Processing of "Redirect" Transmission Service Request:

Upon receiving the redirect request for a particular transmission service request, the TSR group engineers perform MUST analysis to determine the distribution factors of the new path on the constraints identified in the original request analysis and all the constraints with the new redirected path. If the path has a greater than 3% impact on the OTDF or greater than 5% impact on the PTDF, then the request for redirect transmission service is denied. If the impact on old constraints and new constraints is less than or equal to the thresholds mentioned above, then the redirect request is accepted. The intent of this check is to ensure that the impact of the redirected path, on any flow gate, is not greater than the original path's impact on the flow gates identified when the original TSR was studied.

If the redirect request meets these requirements, the MISO planning staff will request the submittal of two copies of the Specification Sheets which are due within 15 Calendar Days after MISO makes the request by posting comments on OASIS. If MISO does not receive the specification sheets by the posted due date, MISO will refuse the redirect TSR on OASIS. If MISO receives the specification sheets, then the redirect TSR will be accepted and the customer shall have 15 days to confirm the TSR on MISO OASIS. After MISO accepts the TSR, it triggers an automatic timer on MISO OASIS for that particular TSR and customer's failure to confirm the TSR within that 15 day period will result in an automatic refusal of the TSR, also referred to as "Retracted."

5.2.3 Processing of "Original" Transmission Service Request:

When the customer submits an original long-term transmission service request, MISO engineers determine if a System Impact Study (SIS) is required. MISO will determine whether an SIS is required by reviewing the type of request, the duration of the requested TSR and the flow based analysis results. If the start and end times of the requested transmission service are beyond 18 months of the queued date then an SIS is required. If the start and end times of the requested transmission service both fall within 18 months of the queued date, then it is up to the discretion of MISO to decide if an SIS is required. If the OASIS Automation tool results indicate significant constraints, which in the engineer's judgment cannot be mitigated during the requested service period, then the request will be refused or counter-offered for a period with no constraints.

If the source for the requested NITS TSR is a MISO aggregate deliverable resource, as identified during the Generation Interconnection NRIS deliverability study or through a market transition deliverability test as a result of a Transmission Owner integration, then the request can be accepted without further analysis for the aggregate deliverable amount. Any incremental MW request above the aggregate deliverable MW amount shall require an SIS.

5.2.4 Application of Rollover Rights for Long-term Firm Service:

General Principles:
Firm transmission service customers with contracts have the right to rollover their service provided the service and the request to roll it over conform to the provisions of section 2.2 of the tariff.

Original Requests:
When a customer requests long-term firm transmission service MISO will evaluate the request for periods beyond the stop date of the request to determine if rollover rights will be available for future periods based on existing firm commitments. If this evaluation determines that sufficient capacity is unavailable to accommodate the request for potential future rollover periods, the Service Agreement will stipulate that the customer will not be permitted to rollover its service beyond the period where sufficient capacity exists. However, the customer has an option to make network upgrades provided it agrees to fund the direct assigned network upgrades, as identified during the Facility Study process, to ensure there is sufficient transmission capacity up until the stop date or beyond the stop date of the TSR.
Subsequent Requests:

In considering subsequent requests for long-term firm service, MISO will not remove capacity associated with a potential rollover from its OASIS. When evaluating the subsequent requests, MISO will assume that rollover rights will be exercised by all prior confirmed requests that are eligible for rollover rights.

If the new request cannot be accommodated, the new customer will have the option of proceeding with an SIS to determine any upgrades necessary to accommodate the request under the assumption that prior confirmed service will be rolled over.
Evaluation or Requests Out of Queue Order:

Situations exist where a TSR is analyzed before a higher queue priority competing request if the two requests cover different reservation periods and study time constraints are an issue – i.e., the lower queue request is to start before the higher queue request and not enough time exists to study the requests in queue priority. An example is if two requests are received and transmission capacity is available for each request in their respective time period but not available for both transactions to occur simultaneously in subsequent time periods.

5.3 System Impact Study Process

After MISO has made the determination that an SIS is required during the Triage process, MISO starts the SIS process with a few administrative steps outlined below.

5.3.1. System Impact Study Agreement

STEP 1: MISO will send the transmission customer an SIS agreement (SISA) within 30 days of receiving the request on OASIS. The SISA will also include a good faith estimate of the time to complete the study. The time to complete the study will depend on the number of studies in the queue, and whether certain studies can be done in parallel with each other. The starting study deposit for a typical SIS is $20,000 which is refundable if there are any unused balances after the study is complete. For multi-party studies, the cost of performing study will be distributed proportionately for the group study based on the MW size of each TSR in the group.

STEP 2: The transmission customer is required to execute and send the SIS agreement (SISA) back to MISO within 15 days after MISO initiates the SISA request. The executed SISA must include the initial $20,000 deposit for the study. If MISO does not receive the SISA and the study deposit within 15 days from the time MISO makes that request, MISO shall refuse the TSR on OASIS. If the 15th day happens to be either on a weekend or a holiday, then MISO engineers will use 10AM of the next first Business Day as the deadline to accept the SISA.

STEP 3: If MISO receives the SISA within 15 days, then it will start the SIS and complete the study within 60 days from the time the agreement and deposit are received by MISO as defined by Attachment J of the tariff.

5.3.2 System Impact Study, Technical Overview

Once the customer sends the SISA and the study deposit, MISO starts the actual SIS. Depending on the duration of the Transmission Service request, whether it is a one year request or starting after the first 18 months after the queued date, the MISO planning staff will utilize OASIS Automation and off-line network analysis evaluation as appropriate.

5.3.2.1 Flow-Based Analysis

The OASIS Automation tool is a flow based analysis tool that is used to evaluate the impact of the requested transfer on all MISO Flowgates. The tool identifies Available Flowgate Capacity (AFC) on all MISO Flowgates with the impact of the requested transmission service for the next 18 months. All long-term transmission service requests with stop dates within 18 months of the queue date are evaluated using the OASIS Automation tool to ensure that there is enough capacity available during the 18 month AFC window. While evaluating TSRs using the OASIS automation tool, MISO uses the queue date of the TSR as the first day for the AFC verification for the next 18 months.

1. If the start date and the end date of the TSR are within the next 18 months of the queued date, then the OASIS Automation tool results are sufficient to either accept or refuse a TSR, unless MISO planning staff believes that further analysis is required and an offline analysis is warranted.
2. If the start and end date of the TSR are beyond 18 months of the queued date, then MISO does not use the OASIS Automation tool results. In such scenarios, MISO will rely on the offline analysis only.
3. If the start date of the TSR is within the next 18 months of the queued date and the end date is beyond the next 18 months of the queued date, MISO uses the OASIS Automation tool and the offline analysis.

4. If the results of the OASIS Automation tool indicate that there is no capacity available on any MISO Flowgate, then MISO will take appropriate action depending on the term of the requested transmission service as mentioned below.
    a. If the start date and the end date of the TSR is within the next 18 months of the queued date, and there are negative AFCs on any Flowgate, then MISO will refuse the transmission service.
    b. If the start date of the TSR is within the next 18 months and the end date is beyond the next 18 months, then MISO will defer the start date of the TSR until there are no negative AFCs. The offline analysis is required to assess system availability beyond 18 months. All other associated Module B BPM requirements still apply such that the minimum term of the TSR must be in the increments of 1 year.

5.3.2.2 Network Analysis Concepts

Model Development

An offline network analysis is used to model the requested transmission service, and the subsequent rollover rights, to determine whether the power can be transferred on the requested path without reliability concerns. Up to three study models may be developed depending on the start and stop dates of the requested service. MISO planning staff will determine the number of models required in consultation with the Ad Hoc Study Group established by MISO planning staff pursuant to section 5.5.1 of this BPM.

The first model is developed to simulate the forecasted summer peak conditions within the next 18 months of the start date of the TSR and is called the near term case.

The second model is developed to simulate conditions during the rollover period of the request, typically 5 years and beyond, from the start date of the TSR and is called the out year case.

A third model may be developed to examine other system conditions (off-peak summer conditions, peak winter conditions, etc.) if it is determined by MISO planning staff that the results of this analysis would be beneficial to the TSR analysis. Items that MISO planning staff may consider when determining if a third model would provide sufficient value to justify development include: (To be determined based on input from affected transmission owners or the customer).

The base cases for the near term and out year cases are built using the Model on Demand (MOD) base case that is updated on a monthly basis by the Model Engineering group. MISO planning staff makes several changes to this case to ensure that the case represents the most accurate topology expected to occur during peak conditions, for the near term and out year scenarios. All changes that are modeled in the cases are outlined below.

- All previously queued Original and Renewal TSRs that have a status of Study, Accepted, or Confirmed are modeled in the base cases.
- All MTEP Appendix A projects that are expected to be in service should be included in each of the models that will be utilized for the study.
- All generator interconnection related transmission upgrades that have gone through the MISO queue process and have a signed GIA.
- Remove known counter flow transactions
- Extend existing rollover right transactions – applicable to long-term transactions
- Near term and out year models are built using MISO Collaborative series summer bus, load, and generator profiles from the Model on Demand (MOD).
- Planning models will be populated with applicable ratings for system intact and contingent conditions. These ratings are developed per FAC-008 and submitted to the MOD tool for existing and future facilities. Normal continuous rating or applicable rating for system intact conditions will be populated into NORM rating field of MOD. Emergency rating or applicable rating for contingent conditions will be populated in STE rating field. For purposes of planning model building, the STE field in MOD stands for Emergency rating or applicable rating for contingent conditions. When producing power flow models from MOD, Rate A will be populated with NORM rating from MOD and Rate B will be populated with **STE (emergency)** rating from MOD for appropriate season.

MISO does not model the following information in their study cases for the evaluation of long-term transmission Service requests.

- Short-Term Transmission Service requests (Less than one year)
- Redirected capacity of confirmed Transmission Service Requests (capacity of original request will be modeled). The reason for not modeling redirected paths is because currently the redirect paths do not have rollover rights. If NAESB approves rollovers for redirect requests, MISO will make appropriate changes to the modeling assumptions.
- Preempted Reservations - Network analysis is performed for firm requests only. Before performing analysis for firm requests, non-firm reservations and any preempted firm transactions identified by the Tariff Administrator necessary for OASIS Automation to accept the request will be removed from the model.
- Counter Flows - Counter-flow reservations are identified by OASIS Automation based on the transaction's effect on flowgate flow and not included in the Automation results. Counter-flow reservations in offline studies are not modeled based on engineering judgment and experience.
- Partial Path transactions - A network analysis evaluation will be performed for all long-term firm transmission service requests based on specified source and sink. If service is accepted, but is a known partial path transaction (i.e., true source and sink is not specified) the transaction will not be included in the base model for evaluation of future requests.

FIRM NITS requests

Requests for NITS must be accompanied by a written application including all of the information located in section 29.2 of the Tariff. The application must be submitted at or near the same time as the OASIS request is made. All requests for Designated Network Resources, whether associated with an initial request for NITS or a subsequent request for a new Designated Network Resource, must include in addition to the information required in the Transaction Specification Sheet of the Application for NITS, the information contained in the form, "MISO Request to Designate a Network Resource."

I) Review of Pre-existing Network Service or Equivalent

MISO will accept requests for initial NITS from Eligible Customers without a system capacity evaluation if the Network Customer provides adequate information for MISO to determine that the network load to be served and the resources designated to supply that load have been planned for in the development of the Transmission System, and do not include new load connection points or new resources that have not previously been associated with supply to the Eligible Customers load responsibility. This will require the following to be demonstrated:

1. Loads to be served are from existing connected load points along with load forecast information for those existing loads. Requests for NITS that include specification of newly connected load points will require evaluation of transmission capacity.
2. Resources designated in the application that are not owned by the Eligible Customer must have existing transmission service arrangements in place (either as a designated resource in a network service arrangement, or PTP service from the resource to a portion or all of the load responsibility). If no transmission service was previously required for supply from these designated resources, there must be an existing contract for supply from the resource.
3. Resources designated in the application that are owned by the Eligible Customer must have existing transmission service arrangements in place if the resource is outside of the Local Balancing Authority Area where any of the load responsibility resides.

If all of the above is verified, Planning will sign the specification sheet, and indicate to the Tariff Administrator that the request for NITS should be accepted.

II) Procedure for Evaluating NITS or Service from New Designated Resource

If the conditions permitting acceptance of the request for NITS without a system capacity evaluation are not met, MISO planning staff will conduct a network analysis and SIS as necessary, using the same steps as in Sections II and III of this Procedure.

These studies shall be done in an analogous manner to the studies performed for an interconnecting generator that requests to be considered as a competing network resource for Load within the Local Balancing Authority Area. The Network Resources and load responsibility of the Network Customer should all be modeled along with all other loads and valid resources for the period under study. The Network Resources under evaluation should be modeled as delivering their output to the load as indicated by the customer and approved by the Ad Hoc Group. Other Designated Network Resources for the Local Balancing Authority Area, or generators within the study region should be reduced proportional to capacity to balance the capacity of the new generator and maintain the net MISO Interchange. The network should then be tested to determine the ability of the aggregate Designated Network Resources for the load responsibility to supply the load under a variety of system conditions within reliability planning standards and criteria consistent with NERC, Regional Entities, and consistently applied Local Balancing Authority Area reliability criteria. These criteria may include among others, the outage of the most critical generator.

5.3.2.3 System Impact Study, Network Analysis Methodology

The ability of all MISO network resources (NRs) to be dispatched to their deliverable capacity to serve network load, needs to be respected while evaluating a new TSR. Therefore instead of a single, fixed base case dispatch, various different generation dispatch scenarios are considered while evaluating the TSR, which adequately ensure that no NR is restricted due to granted transmission service. TSR evaluation is currently being performed using PTI's MUST software.

Contingencies to Evaluate

Single line outages of facilities 100kV and above and pre-defined, multi-element contingencies in the study region would be included in the contingency file. Some areas will be monitored for single line outages of 69kV and above. All such lists will be consistent with applicable NERC, regional and filed local planning standards and are provided to MISO by its transmission owners. The study participants, under the direction of MISO, should obtain the relevant lists for the current study, and determine any other conditions to be modeled.

Monitored Elements

Monitored element files include all facilities 100kV and above in the study region. Some regions will be monitored for facilities 69kV and above. In addition, a complete list of MISO and relevant non-MISO flowgates is also included in the monitored file.

Reliability Margins (TRM/CBM)

MISO will apply the Reliability Margins provided by transmission owners. Flowgates will be provided with CBM and TRM values to be applied to each flowgate. These values should be consistent with NERC and Regional standards applicable to these quantities. For application of CBM and TRM in network analyses where ATC is evaluated on a regional basis, the following approach should be used. Transmission Reliability Margin (TRM) will be included as an adjustment to flowgate capability as provided by the Transmission Owner. This may be a MW reduction or a ratings percentage reduction. Capacity Benefit Margin (CBM) will be applied to all sink control areas based on the control area CBM methodology approved by the applicable NERC Regional Reliability Council (RRC). CBM preservation on intervening Local Balancing Authority Areas will be modeled by reducing the branch ratings on pre-defined flowgates by the designated CBM margin provided for that facility.

Transfer Simulation Participation Points

Transfers will generally be simulated with a Local Balancing Authority Area POR/POD transfer (i.e., proportionally increase generation in the source area and decrease generation in the sink area) unless a specific source/sink is known. In certain situations, the transfer may be modeled as generation to load.

Pre-Transfer Case and Post-Transfer Case.

The pre-transfer case is created by the MISO planning staff as outlined in Section 5.3.2.2 above. The post-transfer case is created by adding the capacity of the requested transmission service request to the pre-transfer case.

DC and AC Contingency Analysis

Based on the established source and sink subsystems, a DC contingency analysis is performed to obtain potential constraint pairs where each pair consists of 1 Monitored Element and 1 Contingency element. A generator sensitivity analysis is performed to obtain potential constraint pairs under worst generation dispatch scenarios. Given the limitations involved in the DC analysis methodology, these results cannot be considered as final. However, they do provide a filtered list of potential constraints that needs to be studied further.

DC Analysis - Creating pseudo Flowgates using DC Analysis:

The following steps takes care of different dispatch pattern of NRs, i.e., all NRs have the right to use transmission service to serve network load up to their deliverable level. The transfer analysis is performed under a large number of reasonably worst-case generation dispatch scenarios. The point of creating all these pseudo Flowgates is to identify potential constraints under worst case conditions.

- The impact of each MISO NR unit, in the study region, on each filtered potential constraint is obtained by performing Monitored Sensitivity analysis. This impact is quantified as generator sensitivity factor (GSF, also referred to as 'DF').
- Based on the assumption of "80-20 rule", the probability of all requested capacity being called on, is greater than or equal to 20%, i.e., at most 15 generators can be called on to their Pmax. Therefore, up to 15 generators with GSFs greater than 5% are dispatched to their Pmax (maximum deliverable amount) sequentially starting from the highest GSF value. Doing so, results in an increase in generation in the study region. Therefore other generation in the study region should be decreased to keep the NSI of the study region the same.
- These pseudo Flowgates for each filtered potential constraint with its associated 80-20 worst dispatch pattern of NRs are created.

AC Analysis

Once the flowgate list is created by using the DC analysis under worst case scenarios, as described, the next step is to take these contingencies and then apply them to the study models; the near term and the out year cases.

1. Perform AC contingency analysis on the pre-transfer case for near term and out year scenarios. Thermal overloads and voltage violations are saved.
2. Perform AC contingency analysis on the post-transfer case for near term and out year scenarios. Thermal overloads and voltage violations are saved.
3. The results obtained from the pre-transfer and post-transfer analysis are then compared to determine thermal and voltage constraints due to the study transfer by using the applicable reliability criteria. The cutoff for consideration as a thermal constraint is a 5% distribution factor of the study transfer on a facility overloaded beyond the applicable rating for system intact conditions, or a 3% distribution factor of the study transfer on a facility overloaded beyond the applicable rating for a contingency condition. The cutoff for consideration as a voltage constraint is a 0.01 per unit voltage change at a bus beyond the applicable bus voltage limits (applies to system intact and contingency conditions).

SIS Report

MISO shall prepare the SIS report within Tariff guidelines and provide the report to the customer within 60 days after receiving the SISA and the study deposit. See the appendix B for the SIS report format.

Ad Hoc Study Group Review and Draft Report

After assimilating all the results from the AC contingency analysis, MISO planning staff prepares a draft report and circulates it to the Ad Hoc Study Group. The goal of providing the report to the Ad Hoc Study Group is primarily to provide comments on the following items:

1. Provide comments on the study models developed by the engineers for the near term and out year scenarios
2. Provide comments on the overloaded transmission elements and provide mitigation which can include the following
    a. Provide correct rating for the equipment
    b. Identify existing transmission operating guides
    c. Identify approved projects that mitigate the thermal constraint
    d. Identify any existing Special Protection Schemes (SPS) or Remedial Action Schemes (RAS) that are in place
3. Provide comments on the validity of the constraints by looking at the contingencies or provide additional contingencies that should be run to meet their respective Planning principles and practices
4. Provide preliminary cost estimates for fixing the overloads on transmission elements.

Evaluating Constraints and Accepting Transmission Service

After receiving feedback and comments from the Ad Hoc Study Group, the transmission planner will incorporate those comments into the report and post the final report on MISO's OASIS. The report will identify all the constraints that are impacted by the Transmission Service request under study and will provide pertinent information to the customer to ensure that the customer can make an informed decision. There are a few permutations and combinations that can occur and can have a different outcome depending on any of the following conditions.

1. External Constraints Only: If the SIS identifies transmission constraints on non-MISO transmission system only, then MISO will assist the transmission customer in coordinating with the non-MISO transmission owners. The customer must submit the Specification Sheets within 15 days after MISO requests the Specification Sheets on OASIS. MISO will provide the customer with all the associated conditions that must be outlined in the Specification Sheets for customer's review. By signing the Specification Sheets, the customer agrees to all the terms and conditions identified in the Specification Sheets. If the external constraint is identified as on the path constraint, then the constraint is ignored and it is not reported upon posting the final

report on OASIS. A corresponding study will need to be completed by a non-MISO transmission provider to fulfill obligations for complete path reservation. However, all the procedures mentioned above will be followed if the identified constraint is off the path constraint.

2. Internal Constraints Only: If the SIS identifies transmission constraints on MISO Transmission System only, then MISO will give the customer a few choices which are outlined as follows.
    a. The SIS report will identify the minimum amount of transmission service that can be granted without any transmission upgrades. If the customer is willing to accept the partial service, then MISO will request the transmission customer to submit the Specification Sheets for the reduced amount. MISO will also check the AFC values for the next 18 months to verify when the partial transmission service is available. If there are no negative AFC values for the next 18 months then MISO will promptly accept and counteroffer the partial transmission service to start at the requested start time. If there is negative AFC before the start date of the TSR, within the next 18 months, then MISO will defer the start date of the TSR until there are no negative AFC. Any counteroffers must have an identical value for the first 12 consecutive months, so if negative AFC is found for any of the first 12 months of the request the counteroffer will be zero for the first 12 months. The customer can submit monthly firm transmission service requests for those months in the 12-month period that have positive AFC. If the requested transmission service is NITS, then MISO will also request the transmission customer to submit an eDNR on MISO OASIS within 15 days along with the Specification Sheets.
    b. The SIS report identifies the upgrades in order to accommodate the full request. Upon posting the final report the customer will be issued a Facility Study Agreement and also a request to submit Specification Sheets to accept partial offer as per the SIS report. See the Facility study section for further details.
3. Internal and External Constraints: If the SIS report includes constraints on both MISO system and non-MISO transmission system then MISO will take the same steps as identified and explained in sections 1 and 2.

4. No Constraints: If there are "NO" constraints identified on the Transmission System then the transmission service planning engineers will look at the AFC results and take action accordingly. If there are no AFC and NNL violations within 18 months of the queued date of the requested TSR, then MISO planning staff will request the customer to submit Specification Sheets within 15 days. If it is NITS, then the customer will also be required to submit an eDNR on MISO OASIS along with the Specification Sheets. After the MISO planning staff receives the Specification Sheets and the eDNR information, the MISO planning staff will request the Tariff Administrator to accept the transmission service on OASIS.

Near Term Results	Out Year Results	Status
Clean	Clean	Accepted
Clean	Constraints	Accepted with no rollover rights or facility study is offered
Constraints	Clean	MISO planning staff determine what upgrade resolved problem in the near term scenario, then accepts conditional on that upgrade. An option would be provided if the customer can accept the service in the out year time frame without any upgrades.
Constraints	Constraints	MISO planning staff engages Ad Hoc Study Group to resolve constraints

A facility will be considered constrained if it becomes overloaded when modeling the transaction, or aggravates an existing overload. The constraint must be impacted by the transaction by a 5% distribution factor with system intact, or 3% under contingent conditions. Regardless of the distribution factor, any impacts under 1MW will be ignored.

5.4 Facility Study Process

5.4.1 Study Coordination Contacts (Ad Hoc Study Group)

When MISO determines that a Facility Study is needed, it will notify potentially affected transmission owners of the need for study. These transmission owners should indicate if they believe the proposed request could impact their systems, and if they desire to be part of the Ad Hoc Study Group, as provided in section 5.5.1, to evaluate the request.

5.4.2 Tender of Facility Study Agreement

In accordance with the Tariff, MISO will tender a Facility Study Agreement to the customer within 30 days of completion of the SIS. If the facility study agreement is not executed within 15 days the application will be terminated and MISO planning staff will notify the Tariff Administrator to refuse the request. The Facility Study Agreement will include an estimate of the actual cost to perform the study. This cost estimate will include the cost of work by MISO planning staff and any other participants, including consultants, involved in the coordinated study. The Facility Study Agreement will also include a good faith estimate of the time to complete the study. The time to complete the study will depend on the number of studies ahead in the queue, and whether certain studies can be done in parallel with each other. The Tariff requires facilities studies be completed within 120 days of receiving the executed study agreement and deposit.

The study deposit for a Facility Study is $100,000 which is refundable if there are any unused remaining balances after the Facility Study is complete. If the customer requests to stop all Facility Study work because it wishes to withdraw the TSR, then MISO will stop all work and refund the remaining balance.